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Sale of Surplus Digester and Landfill Gas to Public Utilities

Camp, Dresser and McKee, Inc., Boston, MA

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SALE OF SURPLUS DIGESTER AND LANDFILL GAS TO PUBLIC UTILITIES

by

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Contract No. 68-03-2803

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16. ABSTRACT

Methane gas produced by anaerobic digestion of wastewater sludge can be upgraded to pipeline quality and sold to a public utility for injection into a natural gas distribution system. Upgrading the gas typically involves treatment for removal of carbon dioxide and hydrogen sulfide, dehydration, and compression.

Upgrading of digester gas to pipeline quality is technically feasible. Moveover, based on current prices of natural gas, selling of upgraded gas to a public utility is economically viable. Although this method of gas utilization has been investigated for several wastewater treatment plants, no such programs have been implemented. The primary reason is that to date, other alternatives (usually involving on-site uses) have been considered more manageable or economical.

Gas generated in solid waste landfills is similar in quality to digester gas. Several landfill gas recovery, processing, and utilization projects (some of which involve selling upgraded gas to a public utility) have either been implemented or are being planned. Because there are no competing on-site uses of landfill gas and because landfill gas quantities are typically much larger than those from digesters, landfill gas has a greater potential for future development by public utilities.

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FOREWORD

The U.S. Environmental Protection Agency was created because of increasing public and government concern about the dangers of pollution to the health and welfare of the American People. Noxious air, foul water, and spoiled land are tragic testimonies to the deterioration of our natural environment. The complexity of that environment and the interplay of its components require a concentrated and integrated attack on the problem.

Research and development is that necessary first step in problem solution, and it involves defining the problem, measuring its impact, and searching for solutions. The Municipal Environmental Research Laboratory develops new and improved technology and systems to prevent, treat, and manage wastewater and solid and hazardous waste pollutant discharges from municipal and community sources, to preserve and treat public drinking water supplies, and to minimize the adverse economic, social, health, and aesthetic effects of pollution. This publication is one of the products of that research and is a most vital communications link between the researcher and the user community.

Anaerobic digestion of wastewater sludge produces surplus energy in the form of methane gas. Decomposition of municipal solid waste in sanitary landfills produces gas similar in composition to digester gas. One method of using the energy in these gases is to upgrade them to pipeline quality and sell them to a public utility for injection into a natural gas distribution system. This report evaluates such a method of digester and landfill gas utilization.

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ABSTRACT

Methane gas produced by anaerobic digestion of wastewater sludge can be upgraded to pipeline quality and sold to a public utility for injection into a natural gas distribution system. Upgrading the gas typically involves treatment for removal of carbon dioxide and hydrogen sulfide, dehydration, and compression.

Upgrading of digester gas to pipeline quality is technically feasible. Moreover, based on current prices of natural gas, selling of upgraded gas to a public utility is economically viable. Although this method of gas utilization has been investigated for several wastewater treatment plants, no such programs have been implemented. The primary reason is that to date, other alternatives (usually involving on-site uses) have been considered more manageable or economical.

Gas generated in solid waste landfills is similar in quality to digester gas. Several landfill gas recovery, processing, and utilization projects (some of which involve selling upgraded gas to a public utility) have either been implemented or are being planned. Because there are no competing on-site uses of landfill gas and because landfill gas quantities are typically much larger than those from digesters, landfill gas has a greater potential for future development by public utilities.

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CONTENTS

Foreword iii
Abstract iv
Tables vi
Abbreviations and Symbols vii
Acknowledgements viii

1. Introduction 1
2. Conclusions 2
3. Evaluation of Digester Gas Utilization by Public Utilities . . . 4
    Gas Quality Requirements 4
    Demand for Gas 5
    Economic Viability 7
    Risk Assessment 8
    Regulatory Constraints 8
4. Evaluation of Digester Gas Treatment to Pipeline Quality 11
    Carbon Dioxide Removal 11
    Hydrogen Sulfide Removal 19
    Dehydration 20
5. Competing Surplus Gas Utilization Methods 22
    In-Plant Uses 22
    Off-Site Uses 24
6. Current Status of Digester Gas Utilization 29
    In-Plant Uses 29
    Off-Site Utilization of Surplus Gas 32
7. Landfill Gas Utilization 35
    Landfill Criteria for Gas Recovery and Utilization 35
    Landfill Gas Composition and Quantities. 36
    Landfill Gas Recovery and Processing Systems 37
    Current Status 39

References 43
Bibliography 44

TABLES

Number		Page
1	Digester Gas and Natural Gas Characteristics	5
2	Absorption Methods for Gas Processing	13
3	Commercial Landfill Gas Utilization Projects	40

ABBREVIATIONS AND SYMBOLS

ac	-- acre
Btu	-- British thermal unit
^{o}C	-- degrees Celsius
CH_4	-- methane
CH_3OH	-- methanol
CO_2	-- carbon dioxide
cu	-- cubic
d	-- day
EPA	-- U.S. Environmental Protection Agency
^{o}F	-- degrees Fahrenheit
ft	-- foot
gal	-- U.S. gallon
ha	-- hectare
H_2	-- hydrogen
H_2S	-- hydrogen sulfide
H_2O	-- water
in	-- inch
kg	-- kilograms
kJ	-- kilojoules
km	-- kilometers
kN/sq m	-- kilo Newtons/square meter
l	-- liter
lb	-- pound
MM	-- million
mgd	-- million gallons per day
mm	-- millimeters
m	-- meters
mg	-- milligram
mi	-- miles
min	-- minute
MW	-- megawatt
N_2	-- nitrogen
O_2	-- oxygen
pH	-- negative logarithm of the hydronium ion concentration; the range extends from 0 to 14, with 7 being neutral.
ppm	-- parts per million
psig	-- pounds per square inch gauge
sfc	-- standard cubic foot
sec	-- second

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Mr. Roland V. Villiers, EPA project officer, provided valuable direction and guidance.

SECTION 1

INTRODUCTION

Methane gas is generated as a byproduct of two municipal waste management activities--anaerobic digestion of wastewater sludge, and operation of solid waste landfills. With proper recovery and treatment, this gas can be upgraded to pipeline quality for sale to public gas utilities. The purposes of this study are (1) to assess the potential future development of using digester gas in natural gas pipelines, and (2) to evaluate the use of landfill gas in this manner.

Anaerobic digestion is widely used in municipal wastewater treatment plants to stabilize sludge. The process is accomplished by maintaining the sludge at about 35 ^{o}C (95 ^{o}F) for about 10 to 30 days in the absence of free oxygen. The organic matter in the sludge is biologically decomposed, and the pathogen content is reduced. The products of decomposition are primarily methane (CH_4), carbon dioxide (CO_2), water (H_2O), and some minor quantities of hydrogen (H_2), nitrogen (N_2), and hydrogen sulfide (H_2S).

Anaerobic digestion produces methane gas. The energy in the gas is greater than the energy required to heat and mix the sludge in the digester, and the surplus gas is available for other uses.

Previously, the most common practice at wastewater treatment plants was to flare the surplus gas. With today's energy costs, however, it has become economically favorable--particularly for plants producing large quantities of gas--to utilize the surplus energy. One method is to sell the gas to a local public utility as an addition to its natural gas distribution system. This method usually requires upgrading of the digester gas to pipeline quality and then conveying it to a distribution pipeline.

Decompostion of solid waste in sanitary landfills produces gas that is similar in composition to digester gas. Several programs of landfill gas recovery, processing, and utilization have recently been implemented, and more are being planned.

In this study, the sale of surplus digester and landfill gas to a public utility for injection into its distribution system was evaluated. This evaluation was accomplished by reviewing the literature and contacting individuals involved in digester gas utilization projects. Information presented in this report includes (1) factors affecting the sale of digester gas to a public utility such as gas quality and quantity requirements, costs, risk assessment, and regulatory constraints, (2) a review of gas purification processes, (3) a review of competing methods of digester gas utilization, including both in-plant and off-site uses, and (4) a summary of the current status of digester gas utilization programs.

SECTION 2

CONCLUSIONS

The following summarizes the principal conclusions of this investigation.

Digester Gas

- Sale of upgraded surplus digester gas to a public utility for injection into a natural gas pipeline is both feasible and economical.

- No such programs have been implemented in the United States, mainly because other gas utilization alternatives have been considered more viable, but the possibilities have been studied at several wastewater treatment plants.

- Wastewater treatment plants usually opt for on-site use of digester gas for the following reasons:

  -- Most of the energy made available by digester gas can be used in-plant.

  -- In-plant programs of gas utilization (e.g., on-site generation of electricity to meet a portion of WWTP power needs) are relatively easy to implement.

  -- The technology for in-plant gas utilization is proven.

  -- In-plant gas utilization requires minimal gas treatment.

  -- Public utilities (which represent the off-site markets for digester gas) tend to believe that using digester gas will only offset a tiny fraction of their natural gas needs while forcing them to accept disproportionate risks in terms of reliability, quality, and institutional factors.

  -- Complete and vague regulatory policies concerning off-site sale of digester gas at every level of government can delay program implementation.

- Alternatives to the sale of surplus gas to public utilities include (1) in-plant use, which is widely practiced, (2) conversion of gas to vehicle fuel and sale, and (3) upgrading and sale to a neighboring industrial private user or other institution. Any of these alternatives may be economical, depending on the individual case.

Landfill Gas

- Gas generated at solid waste landfills is similar in composition to digester gas, and it is generated in relatively large quantities.

- Several programs of recovering and using landfill gas have been implemented or are in the planning stages.

- Compared with digester gas, landfill gas has a greater potential for future development by public utilities because larger quantities are produced and because no competing on-site uses exist.

SECTION 3

EVALUATION OF DIGESTER GAS UTILIZATION BY PUBLIC UTILITIES

Several factors influence a utility's decision to purchase surplus digester gas. These factors include gas quality, available gas quantities, economics, the utility's perception of project risk, and regulatory constraints.

GAS QUALITY REQUIREMENTS

Before gas can be injected into a natural gas distribution system, it must be upgraded to pipeline standards, and it must be pressurized to gas line pressure.

Natural gas consists of about 95 percent methane by volume. Digester gas, on the other hand, contains only about 65 to 70 percent methane. The remainder consists of carbon dioxide (25 to 30 percent), and small amounts of nitrogen (2 to 6 percent), hydrogen (1 to 3 percent), and hydrogen sulfide (0.01 to 1 percent). Digester gas is also saturated with water vapor. See Table 1 comparing the characteristics of natural gas and of digester gas (Pacific Gas and Electric Co., 1981 and USEPA, 1979).

General requirements for purifying digester gas to pipeline standards include removal of carbon dioxide to increase the heating value, removal of hydrogen sulfide to meet air quality standards and to eliminate corrosion, and dehydration to eliminate corrosion and formation of condensate that could restrict flows in the pipeline. Although the requirements vary significantly from one plant to another, gas acceptable for injection into a public utility system typically should have less than 3 percent carbon dioxide, less than 2.7 ppm hydrogen sulfide, a minimum heating value of 36,300 kJ/std cu m (975 Btu/scf), and less than 0.1 mg/l (7 lb/MM cu ft) water. Hydrogen sulfide and water are the most critical contaminants, as high concentrations of either can cause severe corrosion problems.

TABLE 1. DIGESTER GAS AND NATURAL GAS CHARACTERISTICS

Component	Digester Gas	Natural Gas
Methane, %	42.5 - 75	84.5 - 95.71
Carbon Dioxide, %	17.7 - 47.7	0.2 - 0.81
Nitrogen, %	1 - 6.5	0.9 - 15.
Hydrogen Sulfide, ppm	100 - 15,000	<4 - 16
Water, mg/l	saturated	<0.1 (<7 lb/MM cu ft)
Higher Heating Value, kJ/std cu m	17,100 - 29,500 (459 - 791 Btu/scf)	32,100 - 40,400 (863 - 1,085 Btu/scf)

Technologies for gas purification have been developed and proven in the commercial gas industry and can be applied to digester gas treatment. The processes used for gas purification are described in detail in Section 4.

In a few cases involving injection into a large natural gas pipeline, the digester gas may not have to be completely treated to attain pipeline quality. The large gas flow in the utility pipeline may provide a sufficient dilution factor to allow injection of digester gas at a lower heating value. The processing requirements are reduced so that the gas is only compressed and partially treated to remove the water and hydrogen sulfide.

Digester gas is produced at close to atmospheric pressure, but pipelines operate at about 690 to 6900 kN/sq m (100 to 1000 psi); the upper limit represents the pressure required for injection into an interstate pipeline. Compression of the gas is required not only to meet the pressure requirements for injection into a natural gas pipeline, but also to compensate for pressure losses during transport and to increase the pressure at various stages of the processing system.

DEMAND FOR GAS

Most public utility distribution systems have essentially an unlimited gas demand. Therefore, they can accept whatever quantities of digester gas are available. No minimum gas quantity is required to satisfy demand, as the ratio of digester gas to natural gas in the distribution system is very small.

However, sizing facilities for treating digester gas to pipeline qualities can limit allowable digester quantities and flow variations. Future projections of gas production must also be considered. Most gas treatment facilities require a minimum gas flow rate in order to remain cost-effective. A gas-cleaning unit should be designed to treat the average daily gas flow rate, and storage should be provided to handle fluctuations. If the agreement

between the local utility and the wastewater treatment plant requires that the utility be responsible for some or all of the gas treatment facility costs, then the utility will probably specify surplus digester gas quantities and variations. Therefore, surplus energy and gas quantities (including variations in production) must be determined before a digester gas processing and utilization system is designed.

Digester Gas Production

Because digester gas is formed through the destruction of volatile solids, gas production is usually expressed in terms of the volume of gas produced per unit of volatile solids destroyed. For well-operating digesters, the quantity of gas produced is about 500 to 750 l/kg (8 to 12 scf/lb) volatile solids fed to the digester, or 750 to 1100 l/kg (12 to 18 scf/lb) volatile solids destroyed.

Another estimate of digester gas production is 14 to 28 l/capita-day (0.5 to 1.0 scf/capita-day) for primary treatment plants and 34 to 42 l/capita-day (1.2 to 1.5 scf/capita-day) for secondary treatment plants. This estimate is based on 50 percent volatile solids destruction in the digester and a gas production of 940 l/kg (15 scf/lb) volatile solids destroyed.

Variations in Gas Production

Digester gas production can vary significantly. Hourly gas production may be expected to vary from 45 to 200 percent of the average annual rate. These variations are a result of changes in plant flow rates, raw sludge characteristics, bacterial activity, or operating conditions. The effect of these variations must be considered in any proposed use for digester gas. To account for production variations, a storage capacity of 25 to 50 percent of daily production is recommended, but few plants provide this.

Surplus Quantities of Energy from Digester Gas

The amount of combustibles in digester gas determines heating value. Although the hydrogen content has some effect on the heat value (heat of combustion) of digester gas, methane is the primary combustible gas. When methane is burned, water is formed. Therefore, the net, or lower, heat value of the gas equals the heat liberated during combustion minus the heat of water vaporization. The higher heating value of digester gas varies from 18,600 to 27,900 kJ/std cu m (500 to 750 Btu/scf), with a typical value being 24,200 kJ/std cu m (650 Btu/scf). This can be compared with natural gas which has a higher heating value of about 37,200 kJ/std cu m (1000 Btu/scf).

The energy produced by anaerobic digestion is about 8,470 kJ/kg (7.3 MMBtu/ton) dry solids fed to the digester. This energy estimate assumes that the raw sludge is 75 percent volatile solids, the volatile solids are reduced 50 percent during digestion, gas production is 940 l/kg (15 scf/lb)

volatile solids removed, and the gas has a heating value of 24,200 kJ/std cu m (650 Btu/scf). Depending on the ambient temperature, about one-third to one-half of this energy is required to heat the digester. The remaining energy is available for other uses. Assuming a sludge production of 0.24 dry kg/cu m (2000 dry lb/mg) of plant influent flow, this surplus quantity roughly corresponds to 1000 kJ/cu m (3.6 MM Btu/mg).

ECONOMIC VIABILITY

The sale of digester gas to a local utility is viable whenever the price offered by the utility is greater than the costs of treating, compressing, and transporting the gas. This revenue must also be compared with the revenue generated from selling the gas to an off-site private user or the energy savings from utilizing the gas on-site to determine if selling the gas to a utility is economical.

The economics of gas treatment vary from one plant to another. Factors to be considered include quantities and characteristics of surplus digester gas produced, variations in production, and standards of quality required for pipeline injection. The price the utility will pay for the gas is another important factor. The price can vary greatly, depending on the availability and cost of conventional energy resources, and on the utility's assessment of the viability of digester gas utilization.

In 1981, the East Bay Municipal Utilities District (EBMUD) in California estimated that it would cost $2.18/MM kJ ($2.30/MM Btu) to treat their digester gas to meet the specifications of the Pacific Gas and Electric Company for pipeline injection. This cost was based on treating a daily average of 26,500 std cu m (935,000 scf) of surplus digester gas, with a heating value of 21,000 kJ/std cu m (565 Btu/scf), over a 20-year period. The program seemed attractive to EBMUD, since the price of natural gas was $4.27/MM kJ ($4.50 MM Btu). However, the utility would only pay $2.12/MM kJ ($2.24/MM Btu), which is less than the District's estimated cost to upgrade the digester gas. (The District then looked at other options for use of surplus gas and decided to produce power for on-site use and/or sale to the electric utility while recovering system heat (cogeneration). The annual net benefit, after allowing for the costs for producing electricity, was calculated to be $610,000/yr.)

The cost of transporting digester gas to the utility is another important factor. The cost depends on how close the natural gas pipeline is to the wastewater treatment plant. The existing pipeline must also have enough capacity to handle the additional digester gas flow. Economically speaking, the maximum transportation distance for digester gas is one to two miles. Beyond this distance, the pipe construction costs, additional costs for compression to compensate for line pressure losses, and operation and maintenance costs are too high to make off-site use of digester gas economically viable. Also, it must first be determined if the necessary rights-of-way can be obtained.

Ownership of facilities also affects the costs of treatment. The digester gas can be sold "as-is" to the public utility, which would then be responsible for upgrading the gas to pipeline quality. Or, the wastewater treatment plant can provide the digester gas treatment prior to delivery to the natural gas pipeline. If the local utility agrees to provide the gas treatment facilities, the wastewater treatment plant can realize steady revenue from gas sales with almost no capital expenditures. However, ownership of the facility by the wastewater treatment plant could result in lower treatment costs because it is a public agency. A utility would have higher fixed charges than a public agency because of their higher costs of capital.

RISK ASSESSMENT

One of the most significant factors influencing a utility's decision to purchase digester gas is the perceived risk associated with utilization of the energy resource. Although the purification and sale of digester gas for use in a natural gas distribution system appears to be technically and economically viable, utilities have been unwilling to commit themselves, primarily because of the financial risk for relatively small quantities of gas.

The high risk factor associated with digester gas utilization is primarily due to the general view that it involves unproven technology. The general lack of public awareness and available information also contributes to this perception. No experiences involving the upgrading of digester gas for injection into a public utility system, and only a few cases of landfill gas recovery for pipeline injection, have been reported.

The Pacific Gas and Electric Company in California conducted a telephone survey of the 702 wastewater treatment plants in its service area. Of the seven plants producing more than 2,830 std cu m/day (100,000 scf/day) of digester gas, four flare surplus gas. If these plants were to sell their surplus gas to the local utility, they would provide at most only 0.1 percent of the utility's gas supply. The general consensus is that the financial risk in developing such a small energy resource is relatively high.

REGULATORY CONSTRAINTS

Existing regulatory policies can seriously constrain the sale of digester gas because of gas price control, limited government funding, lengthy permit processing, and air pollution requirements associated with gas processing facilities. Also, no specific regulatory policy governs the sale of digester gas to a local utility. Numerous federal, state, and local regulations overlap or conflict in many cases.

In 1975 and 1980, the federal government ruled that the Federal Energy Regulatory Commission did not have jurisdiction over processing and transportation of gas produced from animal wastes or sanitary landfills. Therefore, it can be deduced that digester gas is not regulated by the Federal

Energy Regulatory Commission. However, several Federal legislative acts have potential impacts on the sale of digester gas to local utilities, including the Public Utility Regulatory Policy Act of 1978 (PURPA), the Natural Gas Policy Act, the Federal Power Act, the Clean Water Act, and the Clean Air Act.

One major objective of PURPA is to support development of energy projects. Under Section 201 of PURPA (PL 95-617), the Federal Energy Regulatory Commission issued regulations concerning small power production and cogeneration facilities (< 80 MW). The regulations ensure opportunities to sell electricity at "a just and reasonable price" to utilities when electricity is produced from renewable energy sources such as sludge or from recovered heat. The regulations also eliminate years of permit processing typically required for large energy producers. These provisions may make power generation a more viable alternative than selling the gas to a utility. (See Section 5.)

The Federal Energy Regulatory Commission administers the Natural Gas Policy Act which sets wellhead price controls for natural gas. Currently, these prices are artificially low. Although the price of digester gas is not regulated by this Act, the wellhead price placed on natural gas effectively limits the price of digester gas. (However, lifting natural gas price controls is expected to occur before 1985, the originally scheduled date. When decontrolled, the price of natural gas is expected to equal that of fuel oil. This should in turn increase the price for digester gas.)

If digester gas is injected into an interstate pipeline, the Federal Energy Regulatory Commission has jurisdiction through the Federal Power Act, and a lengthy permit procedure ranging anywhere from six months to two years would be required. However, since few interstate lines exist, digester gas injection will not be very common. Even if the pipeline is not interstate, it is subject to the rules and regulations of the U.S. Department of Transportation, Office of Pipeline Safety.

As part of the Clean Water Act of 1977, anaerobic digestion with greater than 90 percent methane recovery (and with costs less than 115 percent of the most cost-effective alternative) is classified as Innovative and Alternative Technology. This means that qualifying digester gas utilization programs are eligible for 85 percent EPA funding, instead of 75 percent. Eligibility for funding as Innovative and Alternative Technology must be determined on an individual plant basis, taking into account the priority assigned to particular projects and availability of funding.

Federal funding for biomass energy projects is also available under the Energy Security Act, the Alternative Fuels Production Program, and the Supplemental Appropriations and Recision Act of 1980. However, minimum energy production requirements for these funding sources generally preclude digester gas utilization programs from receiving grants. Also, as with the Clean Water Grants Program, the general availability of funding for these projects is an important factor.

On the state level, most utilities are under the jurisdiction of a public utilities commission. Historically, most states have ruled that the public utilities commissions have juridisction only over private corporations. Therefore, construction and operation of digester gas processing and transportation facilities by a municipally owned wastewater treatment plant would not be subject to the rules and regulations of a state public utilities commission. However, there has been no legal decision specifically addressing this issue, and therefore, it must be confirmed on an individual case basis.

The gas processing facilities must meet any state air quality regulations. Obtaining the necessary air quality permits may result in delays in regulatory approval or installation of air pollution control equipment. Also current regulations do not offer similar trade-offs, or off-sets, for digester gas treatment facilities as for other alternative energy facilities such as resource recovery systems. These trade-offs would include such considerations as use of a fuel that otherwise might be wasted.

SECTION 4

EVALUATION OF DIGESTER GAS TREATMENT TO PIPELINE QUALITY

Before digester gas can be injected into a public utility's distribution system, it must be upgraded to meet pipeline standards. Purification usually involves removal of carbon dioxide (CO_2), hydrogen sulfide (H_2S), and moisture from the digester gas.

Gas purification processes are often referred to as scrubbing or sweetening processes. "Sour" gas containing impurities such as H_2S and acidic constituents such as CO_2 is converted to "sweet" gas free of contaminants.

Several commercial gas purification processes have been technologically proven in the petroleum and energy production industry. Many of these processes can be adapted for digester gas purification. However, a common limiting factor is that the quantity of gas required to make treatment economical is typically greater than available digester gas quantities. Selection of the appropriate process(es) for a particular facility depends on many factors, including degree of purification required in relation to raw gas composition, need for recovery of the impurities, quantity of gas to be treated, presence of trace contaminants in the gas, location of the plant, and available financing methods.

Many commercial gas purification processes are proprietary. This means that the process is manufactured and sold only by the owner of the patent or trademark, also called the licensor. A royalty fee is usually involved. The licensor will either provide 1) a turnkey project with design engineering and construction, 2) design engineering and an outside construction contractor under the licensor's supervision or 3) a set of design criteria.

CARBON DIOXIDE REMOVAL

Carbon dioxide is not harmful in gas distribution lines. However, because it is non-combustible, it lowers the heating value. Therefore, CO_2 removal is generally required before pipeline injection. Digester gas typically contains 25 to 30 percent CO_2 as compared to less than one percent in natural gas.

For many CO_2 removal systems, it may be economical to consider including a CO_2 recovery system. The credit for the value of the recovered CO_2 can be used to offset the costs of the CO_2 removal system. It has been estimated that a treatment plant producing 85,000 std cu m/d (3.0 MM scf/d) of raw digester gas may collect up to 63,600 kg/d (70 tons/d) of CO_2. Recovery systems are particularly suited for CO_2 removal systems using solvents with low affinities for methane. The H_2S in the recovered CO_2 can easily be removed by one of the

processes described in the next subsection.

If CO_2 is recovered, it should be in liquid form for easy storing and shipping. Recovered CO_2 is converted from gas to liquid by passing it through a refrigeration unit under pressure at about -20°C (-4°F). The condensed CO_2 is stored in refrigerated and insulated tanks at about 2,100 kN/sq m (300 psig). The tanks can be equipped with external vaporizers to produce gaseous CO_2 when necessary.

There are four applicable methods for separating CO_2 from digester gas:

- o Absorption (physical and chemical)
- o Adsorption
- o Cryogenic separation
- o Membrane separation

Most of these processes remove H_2S in addition to CO_2. Physical absorption in water is the oldest and most economical method of gas purification in wastewater treatment plants (Ashare, et al, 1978). Commercial chemical absorption processes are less economical because of high heat requirements for solvent regeneration. The economics of adsorption on molecular sieves are similar to that for chemical absorption. The cryogenic process has been tested at two wastewater treatment plants, but was not successful in either case. Although the membrane separation process has not been tested in a full-scale facility, the economics look favorable.

Absorption

Gas purification by absorption involves the transfer of impurities to a liquid. Absorption processes generally involve feeding the raw gas to the bottom of a tower and the solvent to the top of the tower. Treated gas is vented from the top, and the solvent leaves the bottom to be regenerated. The towers are either packed, plate, or spray towers. There are two major categories of absorbing processes, physical and chemical, depending on the type of bonding between the absorbed substance and the solvent. A summary of available physical and chemical absorption processes is provided in Table 2.

In the physical absorption process, CO_2 is dissolved in water and carbonic acid is formed:

$$CO_2 + H_2O = H_2CO_3$$

This is called physical absorption because the bonds between the CO_2 and solvent are physical. Physical absorption tends to be more efficient at higher pressure when the solvent can carry more CO_2, and is therefore preferred when the gas must be delivered at a high pressure. The solvent is regenerated by flashing — suddenly decreasing the pressure. Sometimes stripping with an inert gas is required in addition to flashing.

Proprietary corrosion inhibitors and processing schemes have also been developed to allow regeneration temperatures below 110°C (230°F) without causing corrosion.

TABLE 2. ABSORPTION METHODS FOR GAS PROCESSING

Process	Licensor	Solvent	Characteristics
Physical Absorption			
Estasolvan	Developed jointly by Institut Francais du Petrole of France and Friedrich Uhde, G.m.b.H of West Germany	Tributylphosphate	o Simultaneous absorption of acid gases and liquified petroleum gases followed by separation by fractional distillation. o As of 1974 demonstrated in pilot plants but not commercially applied.
Fluor Solvent	Fluor Engineers and Constructors	Propylene Carbonate	o Best suited for gases with high CO_2 and H_2S concentrations. o Regeneration by letdown of pressure.
Purisol	Lurgi Mineralotechnik G.m.b.H	N-methyl-pyrrolidone (NMP)	o Best suited for plants with high throughputs because of complex scheme. o Can selectively remove H_2S.
Rectisol	Lurgi Mineralotechnik G.m.b.H and Union Carbide-Linde Division	Methanol	o Uses low temperatures and high pressures. o High purity of gas achievable. o Very complex scheme.
Selexol	Allied Chemical Corporation	Dimethyl ether of polyethylene glycol (trade named Selexol solvent)	o Expensive solvent, but low operating costs. o Dehydrates gas to pipeline standards. o High thermal efficiency. o Regeneration by four stages of flashing and stripping.

TABLE 2. (Continued) ABSORPTION METHODS FOR GAS PROCESSING

Process	Licensor	Solvent	Characteristics
Water Scrubbing	None	Water	o Regeneration by releasing pressure. o Simple and inexpensive. o Can recover energy with turbine coupled to water-pump motor. o Poor CO_2 removal efficiency. o Other gas components such as methane also partially removed.
Chemical Absorption			
MEA Scrubbing	Union Carbide, Black, Sivalls and Bryson, Inc.	Aqueous solution of monoethanolamine (MEA) and C&I/Girdler, Inc.	o Advantages: high reactivity and solution capacity, low solvent cost, high alkalinity, good stability. o Disadvantages: high vaporization losses, MEA's formation of irreversible reaction products with impurities highly corrosive during regeneration, high heat requirements during regeneration.
DEA Scrubbing	Fluor Engineers and Constructors, Inc. Black Sivalls & Bryson, Inc., The Ralph M. Parsons Co.	Diethanolamine (DEA)	o Advantages (over MEA): lower vaporization losses, low reactivity with impurities, less corrosion. o Disadvantages (in comparison with MEA): lower reactivity higher solvent cost, vacuum

TABLE 2. (Continued) ABSORPTION METHODS FOR GAS PROCESSING

Process	Licensor	Solvent	Characteristics
			distillation may be required to reclaim contaminated solutions. o TEA (triethanolamine) is sometimes used for specialized situations.
Fluor Econamine	Fluor Engineers and Constructors, Inc.	Diglycolamine solution (DGA)	o Process scheme is identical to MEA. o Can be used in more concentrated solutions than MEA thus reducing recirculation and steam requirements. o Expensive. o Corrosive.
Alkazid	Developed by I.G. Farben Industries in Germany, manufactured by Davy Powergas	Alkazid 'M'-removes either CO_2 or H_2S Alkazid 'DIK'-removes H_2S Alkazid 'S'-for gases with additional impurities	o Noncorrosive solutions. o Low vapor pressure resulting in no solution losses. o Minimal loss of hydrocarbons. o Can treat gases at atmospheric or elevated pressures. o Regeneration by heat.
Benfield	Benfield Corp.	Hot potassium carbonate plus activating additives	o Operates at about 240°F and 100 to 2,000 psig. o Regeneration by heat. o High purity product gas with negligible CH_4 losses. o Process is corrosive and salt crystals can form. o Anti-foaming agents may be required.

TABLE 2. (Continued) ABSORTION METHODS FOR GAS PROCESSING

Process	Licensor	Solvent	Characteristics
			o A more expensive improved version, HiPure, has been developed recently.
Catacarb	Eichmeyere & Associates	Solution of a salt and a non-toxic, stable, corrosion-inhibiting catalyst	o High treated gas purity. o Lower energy consumption and smaller equipment than Benfield.
Giammarco-Vetrocoke	Giammarco-Vetrocoke of Marghera, Italy	Aqueous sodium or potassium carbonate solutions with arsenic trioxide	o Arsenites increase absorption rate and capacity. o Noncorrosive solutions. o Arsenite solution is toxic. o Regeneration by heat.
Physical/Chemical Absorption			
Sulfinol	Shell International Research Mij, The Hague, The Netherlands, and Shell Development Co., Houston	Mixture of sulfolane, diisopropanolamine (DIPA), and water	o Unique process using a mixture of chemical and physical solvents with the ratio used dependent on application. o Increased solution capacity, especially at high operating pressures. o Stable, noncorrosive solvent. o Regeneration by flashing and stripping at elevated temperatures.

Physical solvents used to remove CO_2 from gas include water, methanol, and anhydrous organic compounds (See Table 2). H_2S removal can also be achieved. Characteristics of physical solvents include a high capacity for acid gases coupled with a low capacity for hydrocarbons in the gas, low vapor pressures, low viscosity for easy handling, non-corrosiveness, reversible reactions with any constituent in the gas stream, and physical bonds weak enough for regeneration.

In the chemical absorption process, carbonic acid reversibly reacts with solutions of amines or salts of strong alkalis with weak acids and forms carbonates:

With amines

$$R\text{-}NH_2 + H_2CO_3 = (R\text{-}NH_3)_2\ CO_3$$

With alkalines

$$K_2CO_3 \text{ (alkalines)} + H_2CO_3 = 2KHCO_3$$

The solvent is regenerated by breaking the chemical bonds, and it therefore requires a large amount of energy. Heat in the form of steam is usually applied for regeneration.

Absorption processes using alkanolamines have been in use in the U.S. since the 1930s. Since aqueous amine has a low affinity for hydrocarbons, it can be used for methane gas purification. One family of alkanolamine, the ethanolamines, is widely used for CO_2 and H_2S removal. Ethanolamine absorbents are regenerated by stripping at 110 to 116°C (230 to 240°F). Because of corrosion problems with ethanolamine systems, several proprietary corrosion inhibitors have been developed.

Monoethanolamine (MEA) is the most widely used CO_2 removal process in existing commercial gas purification plants, but it is gradually being replaced by more efficient systems. However, it is still used for H_2S removal systems. Diethanolamine (DEA) is the second most widely used absorption process in existing plants.

Shell Oil Company has developed a sulfinol process based on the principle of CO_2 and H_2S absorption at high pressure, and on solvent regeneration by pressure reduction without heat.

The Fluor Corporation has developed a gas purification process that uses diglycolamine (DGA). This process is preferred over MEA because of lower utility costs due to reduced circulation rates, low freezing points, and ability to remove mercaptans.

The hot potassium carbonate (K_2CO_3) process developed by the U.S. Bureau of Mines is primarily used for bulk H_2S and CO_2 removal at high pressure. Although this process is inexpensive and regeneration is relatively easy, it cannot produce a pipeline quality gas.

Adsorption

Gas purification by adsorption involves the selective accumulation of CO_2 and other impurities on the surface of a solid substance (the adsorbent) as a result of physical or van der Waal forces. Commercial adsorbents consist of porous granular compounds with high surface area to weight ratios. Adsorbents generally used for gas purification are silica, activated alumina, activated carbon, or silicates known as molecular sieves. The molecular sieves have proven the most successful and economical adsorbents for gas purification, especially gases with large quantities of CO_2 and small quantities of H_2S.

Advantages of the adsorption process include high removal capacity, simple flow scheme, few problems with corrosion and foaming, capability of treating small quantities of gas, and, depending on the type of adsorbent used, removal of water only or water and other impurities. Disadvantages of the process are high initial cost, high pressure drop, large heat requirement, susceptibility to poisoning, and tendency to plug due to carbon deposits forming in the presence of oxygen, or sulfur deposits forming from adsorbent reactions with H_2S.

Adsorption-regeneration systems usually consist of dual-bed units, with one bed being regenerated while the other is adsorbing. The adsorption process requires high pressure and temperature. Regeneration is usually accomplished by vacuum and/or passing hot gas through the bed.

Three of the better-known adsorption processes are the Molecular Sieve Process by the Linde Division of the Union Carbide Corporation, the Molecular Sieve Process by Marsco Engineering Corporation, and the Getty Synthetic Fuels Process. The Union Carbide and Marsco processes are similar. The Marsco process is better suited for treating small quantities of gas because the entire system is available in skid-mounted units. The Getty Synthetic Fuels process has been used successfully to treat landfill gas to pipeline quality. In this process, gas is passed under pressure through a tower filled with activated carbon to remove H_2S, hydrocarbons and water. Next, the gas is passed under higher pressure through a larger tower filled with a molecular sieve, Zeolite, to remove CO_2. The first tower is regenerated by heat, and the second tower is regenerated by vacuum.

Cryogenic Method

The cryogenic process involves separating the CO_2 from the gas by fractional condensation and distillation at low temperatures. Water, H_2S, and other impurities can be removed by this process. One advantage is that the CO_2 is removed in liquid form and can easily be recovered for another use. Disadvantages of the cryogenic process include a complex flow scheme, low thermal efficiency, high capital costs and high utility requirements. The process has been used for removing CO_2 from digester gas by the Los Angeles County Sanitation District and by Cryenco Engineering Company for the City of Littleton, Colorado, but it has not been successful in either case. Further development is necessary before the process will be commercially available for digester gas treatment.

Membrane Separation

In a membrane separation system, impurities are removed by passing the gas across an ultrathin membrane permeable to water, H_2S, and CO_2. Advantages include lower energy requirements and compactness. Because this process has not been operated commercially, capital and maintenance costs or membrane service life have not been substantiated. A major drawback is that a significant amount of methane is also lost through the membrane. Some of this methane lost in the waste stream may be recovered by adding additional membrane units. Researchers hope to increase methane recovery to over 70 percent. The membrane process is licensed by General Electric Corporation.

HYDROGEN SULFIDE REMOVAL

To meet pipeline standards, the hydrogen sulfide concentration of the digester gas must be reduced to less than about 4 ppm (0.25 grains/100 cu ft) to eliminate corrosion problems. Raw digester gas can contain anywhere from 100 to 10,000 ppm H_2S.

Most CO_2 removal processes also remove H_2S. However, some CO_2 removal processes must be preceded by H_2S removal to prevent corrosion of the CO_2 removal system, or if the CO_2 solvent used has such a high affinity for H_2S that a large amount of energy is required for regeneration. Hydrogen sulfide removal systems may also be required to treat the acid gas stream created during regeneration. The CO_2 in the acid gas stream can be discharged directly to the atmosphere without violating federal regulations. However, H_2S emissions may be restricted because of the objectionable odor.

Methods for removing H_2S from gases in industrial applications can be classified as chemical absorption, physical absorption, dry oxidation to form sulfur or oxides, or liquid oxidation to form sulfur. The absorption processes are described in the previous subsection. The major difference between dry and liquid oxidation processes is that the oxidant or catalyst in liquid oxidation processes is suspended or dissolved in a liquid medium. Most of the commercial H_2S removal processes are used for processing larger quantities of gas, or gas containing higher concentrations of H_2S than typically produced in wastewater treatment plants.

The iron oxide process, or iron-sponge scrubber, is the oldest and most common process for removing H_2S from digester gas in wastewater treatment plants. It is also one of the simplest methods. The "sponge" consists of iron oxide mixed with hardwood shavings to provide bed porosity. The iron oxide reacts with the H_2S to form nonvolatile ferric sulfide. Theoretically 0.6 kg of H_2S will be removed for each kilogram of iron oxide. Non-oxidizable agents such as CO_2 are not removed in the process. If there are oils and greases entrained in the digester gas, the iron-sponge can become fouled. The sponge is regenerated by passing air through the bed to oxidize ferric sulfide to elemental sulfur and ferric oxide. Regeneration should be done slowly and carefully because enough heat is generated to ignite the wood shavings if the reaction is too rapid.

For larger treatment plants, it has been suggested (although not actually demonstrated) that a Claus or Stretford process may be more economical than the iron-oxide process. In the Claus process, which can be used to recover high-purity elemental sulfur, the H_2S in the acid feed gas is oxidized to sulfur by burning with stoichiometric quantities of air to sulfur over a catalyst at about 218°C (425°F). The gas is then passed through a condensor to separate liquid sulfur from the process gas. The Stretford process is widely used commercially in Europe. The H_2S is absorbed by an alkali solution and then removed by oxidation to elemental sulfur.

DEHYDRATION

Moisture is the most objectionable impurity in digester gas. Digester gas is typically generated at 35°C (95°F) and 100 percent saturation. The temperature of the gas falls as it is transported through pipelines, however, causing the water vapor to condense. The liquid will then react with CO_2 and H_2S and corrode the pipeline. The water vapor can also freeze and block control valves, pipe fittings, and even lines. For these reasons, pipeline specifications usually limit water content to less than 0.1 mg/l (7 lb/million cu ft).

As the digester gas is collected, transported, and processed, it goes through pressure and temperature changes which can cause condensation. To drain the condensate so that it does not interfere with gas flow, traps and drains should be placed at low points in the piping, and the pipes should have a minimum slope of 10 mm/m (0.125 in/ft). A condensate collector (knockout pot or scrubber) should be provided wherever condensate is expected to form. Condensate collectors are necessary ahead of the compressors. Knockout pots are also required just before the treatment facilities to collect condensate from the gas cooled after discharge from the compressor.

Before the gas can be injected into a public utility's system, the dew point of the gas must be lowered below the maximum pressure and ambient temperature of the natural gas pipeline. To reach the required dew point, the gas can be dehydrated.

Several dehydration processes are available commercially. The two most common methods of dehydration are absorption by hygroscopic liquids and adsorption on activated solid desiccants. A third method, condensation by compression and/or cooling, is economical only in special situations. Therefore, only the first two methods will be reviewed here.

Absorption

Glycol, a hygroscopic liquid, is the most commonly used absorbent for removing moisture from gas. The two glycols normally used are diethylene glycol (DEG) and trietheylene glycol (TEG), with TEG being the preferred absorbent for achieving maximum dewpoint reduction. Advantages of using glycols include good thermal and chemical stability and hygroscopicity, moderate cost, availability and low vapor pressure.

After compressing and cooling the gas and removing the bulk contaminants (solids and condensed liquids) with knockout pots, the gas is passed up through an absorber/separator tower. In the lower part of the tower, a separator removes any free liquid in the gas. In the absorber section, water vapor is absorbed by contact with a counter current of concentrated glycol solution. The glycol solution is regenerated by inert gas stripping with heat application, or by vacuum in larger installations requiring maximum dehydration.

Adsorption

Desiccants commonly used in gas dehydration processes include silica gels and beads, alumina, activated bauxite, and molecular sieves. The water vapor in the gas is adsorbed to the solids by physical bonds.

Adsorption dehydration systems are usually double units with one adsorber being regenerated while the second is used for dehydration. Regeneration is accomplished by passing hot gas through the beds. If trace amounts of oxygen are in the gas stream, it can react with hydrocarbons to form water and carbon dioxide during regeneration which will reduce the capacity of the system. Other disadvantages of the desiccant process include high initial cost, high pressure drop, susceptibility to poisoning or break-up, and high heat requirements. Advantages of the process over glycol absorption systems include extremely low dewpoint, tolerance of moderate gas temperature, flow rate, and pressure changes, simple design and operation, and few problems with corrosion or foaming.

Desiccants are commonly used for dehydration, and no proprietary processes are involved.

SECTION 5

COMPETING SURPLUS GAS UTILIZATION METHODS

At wastewater treatment plants in the United States, the most common use of digester gas is as fuel for maintaining the digester at optimum temperature, about 35°C (95°F). Typically, untreated digester gas is fed to boilers for combustion, generating steam or hot water. The steam or hot water is then used to heat the raw sludge being fed to the digester by steam injection or pumping the sludge through external heat exchangers. Depending on the ambient temperature, about one-third to one-half of the digester gas produced is required to heat the digester, and the remaining is available for other uses.

The surplus gas can be flared, used to satisfy other plant energy needs, or sold to off-site users such as public utilities (the subject of this study) or nearby industries. The alternative(s) implemented at a particular plant will depend on local power costs, plant energy requirements, surplus gas quantities and characteristics, proximity of off-site potential gas users to the plant, and existing facilities.

If the quantity of surplus gas is small, or if the projected energy savings do not justify the costs to operate a gas utilization program, the surplus gas is flared. However, this "do-nothing" approach is becoming less popular because of today's energy prices.

IN-PLANT USES

Sludge digester gas was first used for lighting at the Exeter, England plant in the 1890s and for power at Matunga, India, in 1902. However, widespread use of digester gas did not occur until the 1930s when it was used mainly for digester and plant heating. Technological advances in the 1940s such as the development of the dual-fuel engine capable of utilizing varying quantities of digester gas and auxiliary fuels, allowed plants to use digester gas without being affected by variable supply.

During the 1950s and 1960s, use of digester gas at municipal wastewater treatment plants increased only moderately, primarily because of the availability of cheap power and fuel. Moreover, the use of anaerobic digestion declined in favor of alternative energy-intensive stabilization processes with fewer operating problems.

In the past decade, energy costs and requirements at wastewater treatment plants have increased significantly. Energy costs have more than doubled in the last ten years due to the worldwide economic and political situation, and

the uncertainty of future energy supplies. At the same time, many wastewater treatment plants have been upgraded to secondary treatment and, in some cases, tertiary treatment. In general, the higher the degree of treatment provided, the more energy consumed. Digester gas can be used to help meet this energy demand.

Alternative in-plant uses for the surplus gas include space heating and cooling, fuel for engine-driven machinery, power generation, and fuel for sludge incinerators. These uses carry varying requirements for removal of gas contaminants; treatment can be minimal or unnecessary when the gas is used to fuel boilers or high-temperature internal combustion engines.

Space Heating and Cooling

Steam or hot water generated in boilers fired by digester gas can be used to heat buildings and equipment areas at the plant. In the warmer months, the steam or hot water can be used to regenerate refrigerant in an absorption chiller which can provide chilled water for cooling.

Engine-Driven Machinery

Digester gas can be used as a fuel for developing mechanical power in internal combustion engines, which in turn drive air blowers or pumps in a wastewater treatment plant. Two types of internal combustion engines are used, depending on the availability and costs of diesel fuel and natural gas. The dual-fuel engine runs on the diesel cycle (pressure ignited) with a small amount (about 8 percent) of diesel fuel oil being injected into the cylinder at the end of the compression cycle. The oil ignites and in turn ignites the gas. This type of engine will operate at gas:oil ratios from about 92:8 to 0:100. The dual-fuel engine is used when diesel oil is the most economical auxiliary fuel available. The second type of internal combustion engine is spark-ignited. It can run on digester gas with natural gas or propane as an auxiliary fuel. Engine controls permit digester gas to be phased in and out, depending on availability, without stopping the unit. Where natural gas or propane is cheaper than diesel and is available, the spark-ignited engine is generally selected.

Internal combustion engines normally convert about 35 percent of the fuel value of the gas to useful work. The remainder of the fuel value is rejected as heat. Equipment to recover heat from the jacket water and exhaust can increase the overall thermal efficiency to about 70 percent. Recovered waste heat is usually used to heat digesters or buildings.

Power Generation

Generators driven by gas-turbine or internal-combustion engines can use digester gas to generate electricity. Most primary treatment plants produce sufficient quantities of digester gas to satisfy all normal power needs. Depending on pumping requirements, secondary treatment plants can meet 40 to

80 percent of their power needs. This method of gas utilization also provides a source of standby power in case of power utility outages.

Turbines fueled by digester gas have had limited use because their fuel consumption is considerably higher than internal-combustion engines, and the efficiency is reduced to about 20 percent. Maintenance problems can result from fouling by contaminants in the digester gas. However, new developments in turbine technology and the fact that turbine engines emit less nitrogen oxides than internal combustion engines might increase the use of gas turbines.

Fuel cells, or hydrogen-oxygen batteries, are another proposed method for converting digester gas to electricity. Hydrogen is obtained from digester gas by passing the gas through a steam reformer. Oxygen is obtained from the air. The fuel cell efficiency is about 70 to 80 percent. However, fuel cell technology is still in the development stage and has yet to actually be used at any wastewater treatment plant.

Sludge Incineration

Digester gas can be burned in sludge incinerators. Fuel is required during startup and may be necessary to sustain combustion, depending on the sludge moisture and volatile solids content. Afterburners also require fuel.

Process Heating

In addition to anaerobic digestion, other treatment processes require heat. These processes include liquifying scum before incineration, heat conditioning, heat drying sludge, lime recalcination, granular and powdered activated carbon regeneration, and ion exchange regenerant renewal.

OFF-SITE USES

For some wastewater treatment plants, especially those located near large users of natural gas, an off-site digester gas utilization program might be more viable and less costly than using the gas on-site. Also, a few large primary wastewater treatment plants produce enough digester gas to meet in-plant demands and still have surplus gas available for off-site uses. In addition to selling the surplus digester gas to a public utility, other off-site uses include selling the gas to private industry, cleaning, compressing, and using the gas as vehicle fuel, selling excess steam or hot water produced by gas-fueled boilers, selling electricity produced from on-site cogeneration, and selling methanol produced by chemical conversion of the digester gas.

Digester Gas Sale to Private Industry

Surplus digester gas can be sold as-is, partially treated, or fully treated to a nearby private industrial user. Storage and compression facilities would probably be required at the wastewater treatment plant. If the gas is to be

used to fuel boilers at a nearby industry, the industry would probably be able to accept untreated digester gas with minor boiler equipment modifications. Other private users might require partial treatment of the digester gas, such as dehydration and hydrogen sulfide removal, to ensure effective operation of their equipment. The purchase price offered for digester gas by a private industry should be renegotiable, depending on the current cost of natural gas and the costs for digester gas treatment, compression, and transport, or for equipment modifications.

For a private user to be considered a viable candidate for digester gas utilization, the following requirements must be met. As with gas sale to a public utility, the private user should be within two miles of the wastewater treatment plant to make pipeline transport of the gas economically viable. The private user should be able to utilize all of the available digester gas or, if not, be willing to pool its gas purchase with another nearby user. Provisions to accommodate varying digester gas quantities, such as gas storage facilities and a backup source of energy, are necessary. Depending on the capital costs imposed on the wastewater treatment plant, a long-term commitment might be necessary. To avoid possible conflict with the local public utility the gas should be sold to a private user only on a contractual basis -- through an arrangement not in violation of the local utility's franchise rights.

The main advantage of selling digester gas to a private industry is that in most cases gas treatment requirements are reduced. Disadvantages include stricter gas quantity and flow variation requirements and difficulties in obtaining a long-term commitment.

Wastewater treatment plants currently selling digester gas to a nearby private user include the Hyperion Plant in Los Angeles, CA, the County Sanitation Districts of Los Angeles County, CA, the County Sanitation Districts of Orange County, CA, the Wards Island Plant in New York City, and the Blue Plains Plant in Washington, DC. Hyperion sells its surplus digester gas to an adjacent power plant operated by the Los Angeles Department of Water and Power. Oil refineries purchase surplus digester gas from the Los Angeles County and Orange County wastewater treatment plants. The Wards Island plant in New York City sells its surplus digester gas to a nearby mental health hospital where it fuels boilers to produce steam for both the hospital and the plant. In Washington, DC, a contract was recently negotiated to sell surplus digester gas produced at Blue Plains to the nearby Naval Research Laboratory for use in boilers. Descriptions of these gas utilization programs can be found in Section 6.

Vehicle Fuel

Digester gas can be cleaned and compressed for use as vehicle fuel. About 2.8 cu m (100 cu ft) of natural gas or 5.1 cu m (180 cu ft) of digester gas are required to replace one gallon of gasoline. Before digester gas can be substituted for gasoline, it must be upgraded to the following standards: 94.5 percent methane, less than 5 percent inert gases, less than 0.5 percent oxygen, less than 3 ppm hydrogen sulfide, and 0.16 mg/l (10 lb/million cu ft)

water. The upgraded gas is then compressed to 16,600 or 24,900 kN/sq m (2400 or 3600 psig) for use as vehicle fuel.

Compressed natural gas has been successfully used as a gasoline substitute in motor vehicles for several years. Its advantages over gasoline include low cost, availability, clean burning characteristics, and increased engine life. Digester gas can be upgraded to produce pipeline quality methane suitable for all natural gas applications including use as vehicle fuel.

A simple conversion allows vehicles to run on either upgraded digester gas or gasoline. The basic conversion equipment consists of a storage cylinder, pressure regulator, gas air mixer, fuel gauge and selector control which allow switching to gasoline while driving, and a refueling connection. The equipment can be transferred to a replacement vehicle.

Because of the relatively high costs of a refueling station, the use of compressed natural gas or upgraded digester gas as vehicle fuel is limited to situations where a large amount of fuel is used, such as city cabs, municipal fleets, and utility maintenance vehicles. Refueling stations can be designed to "quickfill" a vehicle in an average of 2 to 5 minutes or to "time fill" a vehicle overnight. Most refueling stations have a combination of both systems.

A pilot system to process digester gas and use it to fuel plant vehicles has been operating since 1978 at the Modesto, California wastewater treatment plant. The plant now plans to expand the system to treat all the digester gas produced for use as a vehicle fuel. A similar pilot unit is expected to go on-line in late 1982 at the Livermore, California, wastewater treatment plant, and several other plants are investigating this digester gas utilization alternative. (See Section 6 for a description of the Modesto and Livermore facilities.) Preliminary economics indicate the total costs of the system can be competitive with the price of natural gas and 1/3 to 1/4 the cost of gasoline. The economical processing capacity ranges from about 700 to 28,300 std cu m/d (25,000 to 1,000,000 scf/d).

Sale of Excess Steam or Hot Water

When digester gas is used to produce steam and/or hot water, the surplus can be sold to a nearby user. This is common in West Germany and other European countries. In the United States, San Francisco's Southeast Water Pollution Control Plant sells surplus steam to a nearby asphalt plant.

For this alternative to be viable, the user must be near enough to the plant so that pipe costs are economical, and pressure and heat losses are not significant. The user should also have a demand that matches the available supply or be prepared to produce its own steam or hot water.

Sale of Electricity Produced by On-Site Cogeneration

Many wastewater treatment plants use digester gas to produce electricity for in-plant use. If the generators are connected in parallel to the existing

power distribution system, an arrangement can be made for the local utility to purchase electricity. Generating units powered by digester gas are currently being installed at San Diego's Point Loma Wastewater Treatment Facility. Excess power from the generators will be sold to the San Diego Gas and Electric Company.

Section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA) ensures opportunities for wastewater treatment plants to sell their surplus electricity to a public utility. PURPA regulations require electric utilities to purchase electricity from qualifying cogenerators at a rate reflecting the cost that the purchasing utility can avoid as a result of obtaining energy from these cogenerators. In some cases, the rate set under PURPA exceeds the purchase price, in that energy produced from these small generators replaces electricity produced by older, less efficient equipment. However, the U.S. Court of Appeals in the District of Columbia recently ruled that this rate may be too high, hurting the public interest. The Federal Energy Regulatory Commission must consider setting a buy-back rate based on a percentage of the so-called avoided cost.

Agreements with an electric utility can provide for simultaneous purchase and sale, or for surplus sale. Under the first arrangement, all the electricity produced on site is sold to the utility at the cogeneration rate as defined in the PURPA regulations. Simultaneously, the plant purchases its electricity from the utility at the standard electrical rate. Under the surplus sale arrangement, only the electricity produced in excess of on-site demand is sold to the utility.

If the rate paid under PURPA exceeds the standard rate paid for electricity, the simultaneous purchase and sale arrangement is economically the most favorable option for the treatment plant. However, there are disadvantages, such as reduced flexibility to handle plant power outages, and operational problems since all the produced electricity is sold to the utility. Disadvantages common to both options include the cost of connections to the utility's grid, and increased responsibilities such as regular report submittals and liability for utility equipment damage. The economic benefits of selling electricity at the cogeneration rate may be outweighed by these disadvantages.

Chemical Conversion

Digester gas can be converted to other compounds such as ammonia, urea, and methanol (CH_3OH). In most cases, methanol production is the most economical process. We know of no full-scale methanol synthesis plants operating on digester gas. But methanol production has been considered in some digester gas utilization studies. Because of the high price, methanol production could yield potentially large revenues. Therefore, its evaluation is warranted here.

To produce methanol from digester gas, hydrogen sulfide must first be removed. "Gas reforming" is carried out under high pressure and temperature, with steam and a catalyst to produce carbon monoxide and hydrogen. Carbon monoxide is then converted to carbon dioxide and hydrogen, at high temperatures and

with steam and catalysts. The methanol is synthesized from the carbon dioxide and hydrogen, and then purified by distillation. The overall stoichiometric equation for methanol production indicates one molecule of carbon dioxide is required for every three molecules of methane. Because of the existing ratio of carbon dioxide and methane in digester gas, carbon dioxide addition may not be necessary. (Carbon dioxide addition is necessary with natural gas.)

If biological denitrification is part of the wastewater treatment process, the methanol produced from digester gas can be used as the carbon source. Other methanol uses include sale to an industry for use in chemical production (such as solvents or fuel for vehicles), space heating, mechanical generation of electricity, or fuel cell production of electricity.

Disadvantages include high energy requirements which result in a loss of more than half the available digester gas energy, need for skilled operators, and a lack of operating data since no known full-scale methanol synthesis plants operate on digester gas.

SECTION 6

CURRENT STATUS OF DIGESTER GAS UTILIZATION

Most of the current interest in digester gas utilization by public utilities has been centered in California. There, the state legislature has adopted utility regulations that make off-site use of digester gas easier to implement. The public utilities in California are actively involved in developing alternative energy sources. Moreover, because several wastewater treatment plants serve large population centers, and because the warm climate reduces in-plant energy demands, larger quantities of digester gas are available for sale.

Several feasibility studies of digester gas utilization, including investigations of surplus gas sale to public utilities, have been conducted. Although we are not aware of any wastewater treatment plants currently upgrading their surplus digester gas to pipeline quality for sale to a public utility, some plants are investigating this alternative. Many plants have implemented alternative gas utilization programs to utilize excess digester gas not required for digester sludge heating. Some of these programs include on-site power generation, off-site uses of digester gas such as selling gas as-is to private contractors or public utilities, and use as vehicle fuel. A brief review of some gas-utilization programs and studies follows.

IN-PLANT USES

Chicago, IL.

The Metropolitan Sanitary District of Greater Chicago operates seven wastewater treatment plants with a combined flow of 5,678,000 cu m/d (1,500 mgd). In 1974, a study was initiated to investigate alternative uses of surplus digester gas. Steam production for in-plant use was recommended, and boilers were put on-line in March 1980. The use of fuel cells which convert the chemical energy of digester gas to electricity and heat is now being considered to increase the utilization efficiency of the digester gas. Possible funding by the Department of Energy for a 40-kilowatt demonstration phosphoric acid fuel cell facility utilizing digester gas is currently being discussed.

Denver, CO.

As part of a 1974 study for improvements to the Denver Northside Wastewater Treatment Plant, digester gas utilization alternatives were investigated. The

study recommended continued use of digester gas for sludge heating, and use of surplus gas to generate electric power with dual-fuel engines. During the design phase of the on-site power generation facilities, it was concluded that scrubbers for H_2S removal would not be required. Currently, funding has not been obtained for construction, and the surplus gas is being flared.

East Bay Municipal Utility District, CA.

A digester gas utilization study for the 28,400 cu m/d (75 mgd) wastewater treatment plant serving the Oakland-Berkeley area was recently completed. The study's main objective was to determine the best use of the 36,800 std cu m (1.3 MM scf) of digester gas produced daily at the plant. Several alternatives were examined, including sale to off-site users, either a private industry or public utility, and on-site generation of electricity. The study recommended on-site generation of electricity, using either turbines or conventional engines fueled by digester gas, with heat recovery equipment to meet all the plant's heating requirements. The cogeneration facility would be connected in parallel to the local utility's electrical grid system. This would allow sale of excess electrical energy to the utility at the cogeneration rate.

A market study identified potential off-site users of the digester gas produced in excess of that required to heat the digesters. Initially the local public utility, Pacific Gas and Electric Company, was willing to purchase the gas as-is (at a price based on the current cost of natural gas and the cost of treatment). It would assume responsibilities for upgrading the gas to pipeline quality at a proposed gas treatment facility adjacent to the wastewater treatment plant, and inject the treated gas into its distribution system. However, when the utility submitted its proposal to purchase the digester gas, the responsibility for upgrading the gas to pipeline standards was left with the District. The offered sale price would have resulted in an economic loss for the District.

The proposal submitted by the private industry required the District to compress, dehydrate, provide storage, and pipe the gas 1.4 km (0.9 miles) to the industry. The District would have realized the largest net project revenue under this plan. The main drawback of selling gas to a private industry is the market stability problem. The long-term stability of revenue from digester gas sale to private industry depends on the long-term viability of the industry. It must remain competitive in its existing market and location. In addition, the industry was unwilling to provide a bond or similar guarantee to protect the District's capital costs, or to agree to purchase all the available digester gas. For these reasons, off-site sale of digester gas was determined less favorable than on-site power generation.

Fresno, CA.

A digester gas utilization study completed in 1979 recommended that the digester gas be used on-site in multi-fuel engines for steam generation. Off-site gas utilization alternatives were also considered, but were not feasible.

Livermore, CA.

A pilot water scrubbing unit similar to the one currently operating at Modesto, California, is being installed to treat 25 cu m/hr (900 cu ft/hr) of digester gas and to operate a maximum of 14 hours per day. The system removes the CO_2 and H_2S from the digester gas by compressing and injecting the gas into the base of a scrubber tower. A counterflow of pressurized water removes the contaminants. The gas is then dehydrated, compressed, and used to fuel plant vehicles. This system is capable of increasing the heating value of the gas to between 36,500 and 37,200 kJ/std cu m (980 and 1000 Btu/scf) with a water content of 0.1 mg/l (7 lb/MM scf) and a H_2S content of about 4 ppm. The quality of the gas meets natural gas pipeline standards. Economic studies show that total cost of the gas is about 1/3 to 1/4 the cost of gasoline in the United States. This pilot unit is funded by the Clean Water Grant Program as Innovative Technology.

Modesto, CA.

The Modesto wastewater treatment plant serves a population of about 100,000 and produces between 5,100 and 8,500 std cu m/d (180,000 and 300,000 scf/d) of digester gas. Central Plants, Inc. (a subsidiary of Pacific Lighting Corporation) installed a pilot system to convert digester gas to vehicle fuel in 1978. The system is similar to the one being installed at Livermore, California. The digester gas is treated to remove carbon dioxide and hydrogen sulfide, dehydrated, compressed, and used to fuel city vehicles. The Modesto plant produces about 240 cu m (8,500 cu ft) of methane daily, which is equivalent to about 320 l (85 gallons) of gasoline. Early in 1982, Modesto decided to install a full-scale system to convert all of surplus digester gas into vehicle fuel.

New York City, NY.

By 2002, the twelve New York City wastewater treatment plants will produce 303,000 std cu m (10.7 MM scf) of digester gas per day. All the plants currently utilize digester gas in some manner. Except for the Wards Island plant (see the following subsection), all of the plants in New York City utilize digester gas on-site. Three plants use digester gas with fuel oil or natural gas to generate essentially all the plants' electrical needs. The engines' jacket water heats the digesters. The Tallmans Island plant recently installed direct-drive dual-fuel engines. They are connected to the main sewage pumps and aeration tank blowers that will utilize all of the available gas in combination with natural gas. At the 26th Ward plant, the City, in conjunction with the Starrett City development, considered a proposal similar to Wards Island to pipe digester gas from the 26th Ward plant to the power plant at Starrett City. That plant supplies heat and electricity to all the buildings in the development. In return, the treatment plant would receive either electricity, steam, or hot water for space and sludge heating. However, a modular combustion unit utilizing solid waste and sludge to produce high pressure steam, instead of a boiler system fed by digester gas, was recommended. With this plan, some excess digester gas, backed up by natural gas and fuel oil, would be used as an auxiliary fuel. The fuel would fire the

primary chamber during start-ups, and the secondary chamber during normal operation, to assure complete burnout of the off-gases and particulates. The remaining six wastewater treatment plants currently use some digester gas in boilers to meet thermal energy requirements. The excess digester gas is burned in waste gas burners.

Philadelphia, PA.

The Northeast and Southwest wastewater treatment plants currently utilize digester gas on-site and flare the surplus. The City is interested in recovering this excess energy. Possible uses of the surplus gas to be investigated include direct fuel source (probably for incineration), power generation, and steam generation.

Sacramento Regional County Sanitation District, CA.

As part of the Sacramento Regional Wastewater Management Program, a Study of Methane Uses was completed in 1976. The study's objective was to determine the best use of surplus digester gas produced at the new Sacramento Regional Wastewater Treatment Plant. Two alternatives were evaluated in detail: selling the excess digester gas to the local public utility, and compressing and treating the gas for use as a vehicle fuel. The study concluded that both alternatives were viable. Another digester gas utilization study is currently being done to update the 1976 report based on current digester gas quantities. It will also reflect the economic and energy changes that have occurred since 1976.

San Diego, CA.

Two 1350-kilowatt digester gas-powered generating units are being installed at the Point Loma Wastewater Treatment Facility. The generators will provide power for the treatment plant, and any excess power will be sold to San Diego Gas & Electric Company. A scrubbing system to remove hydrogen sulfide is also required. Currently, the plant produces about 28,300 std cu m/d (1.0 MM scf/d) of digester gas of which 25 percent is used for digester heating and the remainder is flared.

OFF-SITE UTILIZATION OF SURPLUS GAS

Los Angeles, CA.

The Hyperion wastewater treatment plant uses its digester gas to fuel a power production facility. In turn, the facility operates the entire plant except for the effluent pumps. About 94 percent of the fuel used to operate the dual fuel diesel engines is digester gas, with diesel fuel providing the remainder. The engines are equipped with heat recovery units to provide steam for heating the digesters. Only about 2,400 MM scf of the 3,600 MM scf of digester gas produced daily is used by the power production facility. (The Hyperion plant provides secondary treatment to about one-third of its flow.)

The remaining digester gas, except for a small quantity used for plant heating, is sold to the adjacent Scattergood Plant, a large steam-turbine utility plant operated by the Los Angeles Department of Water and Power. The price of the surplus digester gas sold to Scattergood is negotiated every two years. It is based on an incremental cost-decremental value formula for splitting the profits. The costs incurred by handling the digester gas at the Scattergood plant are subtracted from the going rate for natural gas. The sum of this value, called the decremental value, and the incremental costs incurred by Hyperion to deliver the gas to Scattergood, is divided by two to determine the price of digester gas. About $80,000/year are earned by Hyperion from the sale of excess gas. Arrangements have also been made for Hyperion to provide electric power for start-up purposes to the public utility, in case of a power outage.

County Sanitation Districts of Los Angeles County, CA.

The Los Angeles County primary Joint Water Pollution Control Plant currently produces approximately 198,300 std cu m/d (7 MM scf/d) of digester gas. About 50 percent of the gas is used on-site to fuel boilers for steam generation, and to fuel internal combustion engines driving electric generators and pumps. The surplus untreated digester gas is piped about 0.4 km (0.25 miles) to the Fletcher Oil Company refinery. There, it is blended with natural gas and used to fuel boilers. The price of the digester gas is based on the current price of natural gas and the heating value of the digester gas. The treatment plant is currently being upgraded to secondary treatment. A power production facility is included as part of the upgrading. The digester gas will be used to fuel combined cycle gas/steam turbine generating units. Gas turbines were chosen instead of engines because, at the time of the decision, proven emission control devices for engines were not available. The District, now must meet strict emission requirements. Heat-recovery units are also included to increase the efficiency of the digester gas utilization. The generation facility will be connected to the local utility's grid system for sale of electricity to the utility. The power generation facilities are expected to go on-line mid-1984.

New York City, NY.

The Wards Island plant delivers its digester gas via a pipeline to the nearby New York State Mental Health Hospital. At the hospital, the gas is burned with fuel oil in boilers. It produces steam to meet the heating requirements of both the hospital and the plant.

Sanitation Districts of Orange County, CA.

The Districts operate two wastewater treatment plants and treat a total flow of 8.06 cu m/sec (185 mgd). Digester gas produced at each plant is compressed, stored, and used on-site to fuel screening incinerators and boilers which power internal combustion engines. Gas facilities at both treatment plants are interconnected by a 6,700-m long, 150-mm diameter polyethylene pipe, which allows the gas to be used at either plant. Surplus

gas is piped about 1500 feet to Mobil Oil Corporation. Currently, about 11,300 std cu m/d (400,000 scf/d) of the 107,600 std cu m/d (3.8 MM scf/d) produced is sold to the oil company. However, as more secondary treatment facilities are put on-line at the plant, a greater portion of the gas will be used on-site to fuel internal combustion engines, and less surplus gas will be available for sale. Under the current agreement, the purchase price of the digester gas is calculated monthly at 50 percent of the prevailing rate for natural gas. The minimum required digester gas pressure is 100 Kn/sq m (15 psig). Mobil is required to purchase whatever digester gas is available. If no surplus digester gas is available, the District is required to give 12-hours notice. The contract is renegotiated on a yearly basis.

Washington, DC.

The Department of Environmental Services for the District of Columbia recently negotiated a one-year, renewable sludge gas service contract with the U.S. Naval Research Laboratory. Under this contract, the Naval Research Laboratory will purchase excess digester gas from the adjacent Blue Plains Wastewater Treatment Plant. The contract allows variable digester gas delivery, depending on the plant's sludge heating and mixing requirements and on the naval facility's demand. The estimated annual quantity of excess digester gas is about 4,476,000 std cu m (158 MM scf). The current selling price is negotiable. The U.S. Navy is constructing the connecting pipeline from Blue Plains to the Naval Research Laboratory, modifying the boilers for use of digester gas instead of natural gas. As soon as the modifications are completed, the system will go into operation. The District is currently flaring the excess digester gas at the treatment plant.

SECTION 7

LANDFILL GAS UTILIZATION

Methane gas generated in sanitary landfills is similar in composition to digester gas. As with digester gas, interest in utilizing landfill gas as an alternative energy source has increased.

As municipal waste in landfills decomposes, methane gas is produced. In past years, methane generation and migration in landfills have created potential explosion hazards. Several large landfills have had to install gas collection systems to prevent migration to adjacent properties where explosive mixtures could form. The collected gas can either be vented to the atmosphere or incinerated. With today's energy prices, it has become economically viable for some larger landfills to recover, process, and utilize the gas.

There are various methods of landfill gas utilization: upgrading and injection into a natural gas distribution system; partial upgrading and sale to a nearby industrial user; power generation; steam production; and conversion to liquified natural gas or methanol. This section will briefly describe landfill gas recovery and processing for injection into a public utility gas pipeline. It will include a comparison with digester gas utilization by public utilities and present the current status of landfill gas utilization projects.

LANDFILL CRITERIA FOR GAS RECOVERY AND UTILIZATION

The recommended minimum landfill size for gas recovery and utilization depends primarily on the economics of the gas recovery and collection system, the gas processing equipment, delivery requirements, and final gas use. In general, a minimum quantity of two million tons of municipal solid waste is necessary. Minimum landfill area requirements range from 11.3 ha (28 ac) for an average fill depth of 45.7 m (150 ft) to 31.6 ha (78 ac) for an average fill depth of 15.2 m (50 ft) (Ham, 1979).

Currently, methane gas is being recovered only from solid waste landfills. Gas recovery from sludge landfills is presently not feasible. Sludge landfills are normally much smaller than the minimum landfill size required for economical gas recovery and utilization.

LANDFILL GAS COMPOSITION AND QUANTITIES

Both digester gas and landfill gas are produced in the methane fermentation process in which organic wastes are stabilized by microorganisms under anaerobic conditions. An important difference between the two processes is that optimum conditions are more difficult to achieve in a landfill than in a digester. As a result, no verified kinetic models to predict landfill gas production rates exist. Instead, investigations use simplified models that can be empirically adjusted . Both the composition and rate of production of landfill gas are significantly affected by local environmental factors.

Landfill Gas Characteristics

Landfill gas typically consists of 45 to 65 percent methane, with the remaining constituent primarily carbon dioxide, and traces of nitrogen, hydrogen sulfide, and other gases. It is also saturated with water vapor. The presence of oxygen or nitrogen in the gas usually indicates air intrusion through the landfill cover.

The major difference between landfill gas and digester gas is the reduced methane content in landfill gas. Because there is less methane, the heating value is also less, typically about 16,800 to 20,500 kJ/std cu m (450 to 550 Btu/scf).

Landfill Gas Production

Landfill gas production is time dependent. Production can continue for a few years to several decades after completion of the landfill. The rate of gas production varies during this period. Factors affecting the rate of gas production include quantity and composition of refuse, age of refuse, depth and configuration of the fill, soil permeability, moisture content, temperature, availability of nutrients, and the pH and alkalinity of liquids in the landfill.

The rate of landfill gas generation reaches a peak during the first few years and then decreases exponentially for several years. Typically, the maximum gas generation rate will occur one to five years after the waste is deposited, and it will continue at a high rate for about six to ten years. Gas will then be produced at lesser rates for thirty to one hundred years.

Typical gas production quantities are estimated to be 0.16 to 0.25 std cu m/kg (2.5 to 4.0 scf/lb) of waste, assuming that half the available organic material is decomposed. Actual gas recovery is reduced to about 0.013 to 0.047 std cu m/kg (0.2 to 0.75 scf/lb) because of recovery efficiency, boundary losses, collection losses, and gas generation before and after recovery is in operation. The rate of gas production is estimated to be 0.006 to 0.038 std cu m/kg (0.1 to 0.6 scf/lb) of waste per year.

Gas enhancement techniques can sometimes be used to improve the total yield and the rate of landfill gas production. Some of these techniques include increasing the organic content of the waste (possibly by adding sludge);

excluding industrial wastes containing toxic or inhibitory materials; carefully operating the gas recovery system to prevent air intrusion; increasing the moisture content of the landfill; adding chemicals during refuse placement to control pH and alkalinity and to add nutrients; recirculating the leachate to improve mass transport within the landfill; reducing the particle size of refuse material; and lining the landfill.

Landfill gas quantities are typically greater than digester gas quantities, particularly if a portion of the digester gas is used to heat the digester. For example a 378,500 cu m/d (100 mgd) treatment plant will produce roughly 380 MM kJ (360 MM Btu) of surplus energy daily (see Section 3). Many of the landfills where gas recovery programs have been implemented or are being planned are producing at least twice this amount of energy.

However, major disadvantages are associated with landfill gas production, and not digester gas production. It is difficult to predict how the rate of production will vary with time. Assuming the landfill will someday be closed, the gas supply will eventually be depleted or it will no longer be generated in quantities which make recovery economically feasible.

LANDFILL GAS RECOVERY AND PROCESSING SYSTEMS

Before a gas recovery and processing system is implemented, a testing program should be conducted. In the testing program, information on the operating history of the landfill is analyzed, including types of refuse accepted, moisture addition, and the age and distribution of waste. Field testing is then conducted to determine gas composition, pressure within the landfill, temperature, flow rates, and radius of influence of extraction wells. Field testing involves extracting gas from wells placed at various locations throughout the landfill and at various depths. Testing under static and extraction conditions is necessary to ensure that landfill gas is extracted at the rate it is generated. This helps ensure that air is not drawn into the landfill.

Landfill gas is recovered by utilizing a gas collection system with an exhaust blower, a gas collection header, and a series of extraction wells. Gas is withdrawn by applying a vacuum to each extraction well; gas then enters the system through perforated pipe which makes up the lower third of each well. The gas is then transported to a central location, via the collection header, for processing and/or use.

Depending on how the gas is to be utilized, varying degrees of treatment are required. To improve the gas to pipeline standards, compression, dehydration, pretreatment (to remove contaminants such as hydrogen sulfide and organic impurities that can cause corrosion), and carbon dioxide removal are required. By blending with propane, (which has a heating value of 93,700 kJ/std cu m (2,517 Btu/scf), the heating value of landfill gas can be increased to pipeline quality.

The compression requirements depend on the particular gas treatment process employed, and on the required pipeline injection pressure. Dehydration systems are similar to those used to process digester gas. A typical

dehydration flow scheme consists of a liquid solids separator to remove condensate and particulates, low pressure compression, two stages of cooling, a condensate separator, and a triethylene glycol dehydrator. For smaller quantities of gas, refrigeration dehydration instead of a glycol unit can be used. Depending on the characteristics of the raw gas, various pretreatment systems may be necessary to remove contaminants such as hydrogen sulfide, organic compounds, and any remaining water vapor.

As discussed in Section 4, several gas purification processes have been commercially proven. Because more landfill gas, compared to digester gas, has to be treated, several commercial processes are economically viable. Some carbon dioxide removal processes can be applied to landfill gas treatment. They include chemical and/or physical absorption, adsorption, or membrane filters. One of the most successful and economical carbon dioxide removal processes for landfill gas treatment is the molecular sieve process. Another process presently attracting more attention for landfill gas treatment is the membrane process.

If an unusually large amount of nitrogen is in the raw gas because of air intrusion, it might be necessary to include nitrogen removal in the treatment scheme. The nitrogen is removed by fractional liquification using mechanical refrigeration. With this system, the methane in the gas is liquified and the nitrogen and other impurities are exhausted in gaseous form. The capital and operating costs of a nitrogen removal system are high because of equipment and energy requirements.

Some of the original landfill gas utilization projects, such as Palos Verdes and Mountain View in California, experienced technical problems with their gas processing systems. A severe corrosion problem at Palos Verdes resulted from hydrolysis and decomposition of contaminants that had accumulated in the pretreatment systems and formed sulfurous and hydrochloric acids. The corrosion problems have been eliminated by changing to a corrosion-resistant material in the heat exchanger, by changing the pretreatment system from a mixed bed for dehydration and trace contaminant removal to separate stages of a glycol system for dehydration followed by trace contaminant removal, and by making operational changes in the molecular sieve towers.

At Mountain View, activated alumina, activated charcoal and molecular sieves are used to remove water, carbon dioxide, and organic impurities in the gas. When the desiccant support screens failed, alumina gel was drawn into the vacuum cylinder of the compressor, and moisture adsorption problems with the molecular sieves reduced their effectiveness. These problems were corrected by installing a filter ahead of the compressor and replacing the sieve material with a new, dry material. Other operational problems included malfunctioning motor-operated valves, corrosion, and reduction of gas flow rates to less than half the design capacity to avoid air intrusion. The system has been operating successfully since commercial operation began in January, 1980. However, different processes are being considered for a future expansion, because of the unreliability of the existing gas purification system and the high maintenance costs.

CURRENT STATUS

An evaluation of the current status of landfill gas utilization programs reveals the same constraints as those imposed on digester gas programs. Although gas recovery and processing technology is viable, the lack of available data from existing systems, and operating problems, have resulted in public mistrust of the technology. Technical uncertainties also surround gas generation rates, condensate handling, air intrusion control, and air quality considerations.

Significant marketing constraints occur because of the difficulty in predicting gas production rates and the high risk factor associated with gas treatment technology.

Institutional constraints include the numerous and complex regulations related to landfill gas recovery; the lack of public awareness and available information on existing systems; the stigma associated with landfill operations; opposition by utilities to gas wheeling (using a utility pipeline for a small fee to distribute treated gas to a user); a lack of industry-wide specifications; and questions regarding the legal ownership of the gas.

The world's first commercial landfill gas recovery and utilization system went into operation in 1975 at the Palos Verdes Landfill in Rolling Hills Estates, California. The landfill closed in 1980 after 23 years of operation and receiving 23.5 million tons of solid waste. Getty Synthetic Fuels, Inc., built the recovery and processing system. Today, it produces about 21,200 std cu m/d (750,000 scf/d) of pipeline quality gas which is transported 2.4 km (1.5 miles) to a Southern California Gas Company's natural gas pipeline. Initially, the facility had problems with the collection system and a severe corrosion problem. But, since 1978, it has operated steadily with less than 10 percent downtime.

Since the Palos Verdes gas recovery project went into operation, several others have gone on-line and more are in the planning stages. The landfill gas is treated to varying degrees and used for various purposes. Table 3 summarizes current landfill gas utilization projects. As the regulatory, economic, and technical constraints of landfill gas utilization are overcome, more landfill gas utilization projects are expected to be implemented.

Landfill gas will never represent a major portion of the country's overall energy supply. However, unlike digester gas which can be utilized on-site to meet plant energy demands thus reducing available surplus quantities, landfill gas represents a viable source of energy for public utilities which will probably be utilized more in the future.

TABLE 3. COMMERCIAL LANDFILL GAS UTILIZATION PROJECTS

Location	Major Participants	Gas Production std cu m/d (MM scf/d)	Start-up	Gas Use
Azusa, CA	Azusa Land Reclamation Co.	21,200 (0.75)	early 1978	Low Btu gas sold to nearby Reichhold Chemical Co. where it is fired in boilers to produce steam.
Carson, CA	Watson Biogas Systems, SCS Engineers, Inc.	17,000 (0.6)	February 1982	Medium Btu gas to power generators producing electricity for sale to utility.
Chicago, IL	Getty Synthetic Fuels, Inc.	70,800 (2.5)	December, 1980	High Btu gas sold to Natural Gas Pipeline Co. of America for injection into interstate pipeline.
Cinnaminson, NJ	Public Service Electric and Gas Co.	8,500 (0.3)	September, 1979	Medium Btu gas sold to Hoeganaes, a powder steel plant, where it heats ladles in which steel is melted.
City of Industry, CA	SCS Engineers, Inc.	19,800 (0.7)	Spring, 1980	Medium Btu gas used for heating and cooling at adjacent city-owned convention center.
Duarte, CA	Watson Biogas Systems, Lockman and Assoc.	--	February, 1982	Medium Btu gas to power generators, producing electricity for sale to utility.
Glendale, CA (Scholl Canyon)	City	34,000 (1.2)	June, 1981	Medium Btu gas used as engine fuel for electric power.

TABLE 3. (Continued) COMMERCIAL LANDFILL GAS UTILIZATION PROJECTS

Location	Major Participants	Gas Production std cu m/d (MM scf/d)	Start-up	Gas Use
Los Angeles, CA (Bradley East)	Genstar Gas Recovery Systems, Inc., Conrack Co.	56,700 (2.0)	Late 1980	Medium Btu gas sold to city for startup and boiler fuel at generating station.
Los Angeles, CA (Lopez Canyon)	City	2,800 (0.1)	Early 1981	Medium Btu gas used as engine fuel for electric power.
Los Angeles, CA (North Valley (Sunshine) Landfill)	Getty Synthetic Fuels, Inc.	--	--	Medium Btu gas.
Martinez, CA (Acme)	Getty Synthetic Fuels, Inc.	--	Late 1981	Medium Btu gas used as boiler fuel for electric power.
Monterey Park, CA	Getty Synthetic Fuels, Inc.	113,300 (4)	August, 1979	High Btu gas sold to Southern California Gas Co. for injection into natural gas line.
Mountain View, CA	City, Pacific Gas & Electric Co., EPA	17,000 (0.6)	January, 1979	Medium Btu gas injected into PG&E natural gas line.
Palos Verdes, CA (Rolling Hills Estates)	Getty Synthetic Fuels, Inc.	21,200 (0.75)	June, 1975	High Btu gas sold to Southern California Gas Co. for injection into natural gas line.
Orange County, CA (Coyote Canyon)	Irvine Co.	--	Late, 1980 (testing)	--

TABLE 3. (Continued) COMMERCIAL LANDFILL GAS UTILIZATION PROJECTS

Location	Major Participants	Gas Production std cu m/d (MM scf/d)	Start-up	Gas Use
San Fernando, CA	Getty Synthetic Fuels, Inc.	--	Late 1981	Medium Btu gas.
San Leandro, CA (Davis St.)	Getty Synthetic Fuels, Inc.	85,000 (3)	July, 1981	Medium Btu gas sold to Domtar Gypsum Co. or used as boiler fuel to produce power.
Riverview, MI	Watson Biogas Systems, SCS Engineers, Inc.	--	--	Medium Btu gas to power generators, producing electricity for sale to utility.
Staten Island, NY (Fresh Kills)	Brooklyn Union Gas Co.	2,000 (0.07)	July, 1980	Medium Btu gas used as engine fuel for electric power.
Staten Island NY (Fresh Kills)	Getty Synthetic Fuels Inc.	141,600 (5.0) estimated	March, 1982	High Btu gas sold to Brooklyn Union Gas Co.
Sun Valley, CA (Sheldon-Arleta)	City of Los Angeles Department of Water and Power	82,200 (2.9)	December, 1979	Medium Btu gas used in boilers as supplemental fuel at city's Valley Steam Plant.
Whittier, CA (Puente Hills)	Los Angeles County Sanitation Districts	61,000-122,400 (2.2-4.3) estimated	Spring,	Medium Btu gas to power generators to produce electricity.
Wilmington, CA (Ascon)	Watson Biogas Systems, Inc., SCS Engineers, Inc.	42,500 (1.5)	Late 1978	Low Btu gas sold to Shell Oil Refinery where it is used as boiler fuel.

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